TECHNICAL REVIEW DOCUMENT For OPERATING PERMIT 05OPWE281

Cheyenne Plains Gas Pipeline Company – Cheyenne Plains Compressor Station
Weld County
Source ID 1230051

Prepared by Jacqueline Joyce
September and October 2006
Revised November 2006, January and March 2007
Revised September 2007 to reflect vacatur of Boiler MACT requirements

I. Purpose

This document establishes the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted December 15, 2005, comments on the draft permit and technical review document received on January 11, 2007, additional information submitted on March 30, 2007, various telephone conversations and e-mail correspondence with the source and review of Division files. This narrative is intended as an adjunct to the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

The facility is a natural gas compression facility as defined under Standard Industrial Classification 4922. This facility is a mainline compressor station. Its main function is to compress and transmit natural gas from the Wyoming area east into Kansas. This is achieved by using three (3) natural gas fired combustion turbines driving natural gas compressors. The facility also includes a CO₂ Treatment Plant, which consists of a glycol dehydrator and amine treatment unit. Emissions from the glycol dehydrator still (regenerator) vent and flash tank and emissions from the amine unit flash tank are routed to a flare to reduce VOC emissions. The amine unit regenerator vent is

equipped with a SulfaTreat H₂S control system to reduce H₂S emissions. There are also two (2) 45 mmBtu/hr natural gas fired heaters associated with the amine unit and an emergency generator that are included in Section II of the permit as significant emission units.

The Cheyenne Plains Compressor Station was constructed in 2004 at the site of an existing mainline compressor station (Cheyenne Station), whose main function is to compress and transmit natural gas from the Wyoming area to the Colorado Front Range area. As such the two facilities are considered a single source for purposes of Prevention of Significant Deterioration (PSD) review requirements and Title V permitting requirements. Equipment associated with the Cheyenne Compressor Station is addressed in a separate Title V operating permit (95OPWE090).

The facility is located approximately 4 miles north of Rockport in Weld County on Highway 85. The area in which the plant operates is designated as attainment for all criteria pollutants.

There are two affected states within 50 miles of the plant: Wyoming and Nebraska. Rocky Mountain National Park, a Federal Class I designated area is within 100 kilometers of the plant.

The facility is considered to be a major stationary source (Potential to Emit (PTE) \geq 250 tons/yr). Facility wide potential emissions are shown on the following tables:

Facility Wide Emissions (95OPWE090 and 05OPWE281)

Pollutant	Potential to Emit (tons/yr)								
	95OPWE090	05OPWE281	Facility						
PM ¹	35.23	11.71	46.94						
PM ₁₀ ¹	35.23	11.71	46.94						
SO ₂ ¹	1.33	3.44	4.77						
NO_X	624.3	108.53	732.83						
CO	262.8	153.22	416.02						
VOC	291.3	58.17	349.47						
HAPS	60.7	14.1	74.8						

¹Emissions for each emission unit are typically below the APEN de minimis level, so emission limits have generally not been included in the construction permits and/or Title V permit.

05OPWE281 Emissions

Emission Unit		Potential to Emit (tons/yr)							
	PM	PM ₁₀	SO ₂	NO_X	CO	VOC	HAPS		
Turbine CP CG-7101	2.1	2.1	1.06	31.6	38.5	11.3	See		
Turbine CP CG-7201	2.1	2.1	1.06	31.6	38.5	11.3	Table on		
Turbine CP CG-7301	2.1	2.1	1.06	20.1	20.9	11.3	Page 29		

Emission Unit		Potential to Emit (tons/yr)							
	PM	PM ₁₀	SO ₂	NO _X	CO	VOC	HAPS		
Hot Oil Heater H- 8701	1.58	1.58	0.13	8.9	7.3	3.15	See Table on		
Hot Oil Heater H- 8702	1.58	1.58	0.13	8.9	7.3	3.15	Page 29		
Flare Vent FL-8921	2.25	2.25		7.0	39.42	5.8			
Amine Unit Regenerator (CO ₂) Vent ST-8931						11.8			
Emergency Generator CP EG-6141				0.43	1.30	0.37			
Total	11.71	11.71	3.44	108.53	153.22	58.17	14.1		

The PTE for NO_X , CO and VOC for the turbines, hot oil heaters, flare and CO_2 vent are based on permitted emissions. PTE for PM, PM_{10} and SO_2 from the turbines and heaters are based on AP-42 emission factors and the fuel consumption limits provided in the permit. PM and PM_{10} emissions from the flare are based on AP-42 emission factors for natural gas fired boilers, the design rate of the flare (13.54 mmBtu/hr) and a gas heat content of 300 Btu/scf. Note that emission limits for many of these pollutants were not included in the permit since emissions do not exceed the APEN de minimis levels. The criteria pollutant PTE for the emergency generator is based on emission factors (manufacturer's for NO_X , CO and VOC and AP-42 for PM, PM_{10} and SO_2), design rate and 250 hrs/yr of operation (construction permit exemption under Colorado Regulation No. 3, Part B, Section II.d.1.c.(ii)).

Even though actual emissions are typically much less than permitted emissions, the source usually reports permitted emissions as actual emissions, which is an acceptable practice; therefore actual emissions are not shown in the above tables.

The breakdown of HAP emissions by emission unit and individual HAP is provided on page 29 of this document. As indicated in the footnotes for the table on page 29, the HAP PTE was determined as follows: for the turbines and hot oil heaters, HAP emissions are based on AP-42 emission factors, design rate and 8760 hrs/yr of operation, for the emergency generator, it is based on design rate, AP-42 emission factors and 250 hrs/yr of operation and for the flare vent and amine unit regenerator (still) vent it is based on the GLYCalc run used to set the permit limits.

MACT Requirements

Natural Gas Transmission and Storage MACT (40 CFR Part 63 Subpart HHH)

The glycol dehydrator is subject to the MACT requirements for Natural Gas Transmission and Storage Facilities in 40 CFR Part 63 Subpart HHH and had to comply with the provisions in the MACT upon initial startup. The appropriate requirements for the dehydrator are discussed in further detail under the discussion on the dehydrator later in this document.

Reciprocating Internal Combustion Engine (RICE) MACT (40 CFR Part 63 Subpart ZZZZ)

The final rule for RICE was published in the Federal Register on June 15, 2004. There is only one engine, the emergency generator, associated with the Cheyenne Plains equipment. In accordance with the provisions in 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(1)(i), new or reconstructed existing emergency RICE (commenced construction or reconstruction after December 19, 2002) do not have to meet the requirements in 40 CFR Part 63 Subparts A and ZZZZ, except for the initial notification requirements. Note that the definition of emergency stationary RICE does not include a limitation on hours of operation for emergency situation and for routine testing and maintenance. In addition, an emergency stationary RICE may also operate an additional 50 hrs per year in non-emergency situations. The initial notification was submitted for this engine on December 13, 2004.

Combustion Turbine MACT (40 CFR Part 63 Subpart YYYY)

The final rule for combustion turbines was signed on August 29, 2003 and was published in the Federal Register on March 5, 2004. The turbines are considered "new" turbines (commenced construction after January 14, 2003) and are subject to the MACT. However, in the August 18, 2004 version of the Federal Register, the EPA issued a stay for gas-fired lean premix and diffusion flame turbines. Therefore, the "new" turbines at this facility are only subject to the initial notification requirements and need not comply with any other requirement of 40 CFR Part 63 Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register. An initial notification was submitted for turbines CG-7101 and CG-7201 on June 15, 2005 and an initial notification was submitted for turbine CG-7301 on April 14, 2006.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was published in the Federal Register on September 13, 2004. All the heaters associated with Cheyenne Plains are natural gas fired. There are two (2) hot oil heaters (45 mmBtu/hr), one utility heater (4.5 mmBtu/hr) and the glycol dehydrator reboiler (2 units, total 4.97 mmBtu/hr). The provisions in 40 CFR Part 63 Subpart DDDDD (§ 63.7506(c)(4)) exempt new (constructed after January 13, 2003) small gaseous fired units (≤ 10 mmBtu/hr) from the requirements in 40 CFR Part 63 Subparts A and DDDDD, including the initial notification requirements. The two hot oil heaters are subject to requirements in Subpart DDDDD and an initial notification was submitted on March 14, 2005.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. Provisions have been included in the permit to require the source to submit the 112(j) application. The Division will notify the source of the deadline at a later date.

Compliance Assurance Monitoring (CAM) Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. None of the engines addressed in the current Title V permit are equipped with control devices; therefore, CAM does not apply to any of the equipment included in the current Title V permit.

The turbines are equipped with dry low NO_X (DLN) combustion systems to reduce NO_X emissions. The hot oil heaters are equipped with low NO_X burners (LNB). However, DLN and LNB are not considered control devices as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since DLN and LNB are considered inherent process equipment.

The glycol dehydrator regenerator (still) vent and flash tank vent and the amine unit flash tank vent are routed to a flare to reduce VOC and HAP emissions. Uncontrolled VOC and HAP emissions from the flare vent are 287 tons/yr and 131.9 tpy, respectively. Therefore, uncontrolled emissions exceed the major source level and CAM applies. With respect to HAP emissions, the HAP limit associated with the dehydrator (1 tpy of benzene) is the MACT limit and MACT limits are exempt from CAM as provided for in 40 CFR Part 64 § 64.2(b)(1)(i). Controlled VOC emissions from the flare vent are less than the major source level (permitted VOC emissions are 5.74 tons/yr), therefore, the unit is not considered a large pollutant specific emission unit and a CAM plan is not required until renewal in accordance with the provisions of 40 CFR Part 64 § 64.5(b).

The amine unit regenerator (still) vent is routed to a SulfaTreat system to reduce H_2S emissions. Uncontrolled emissions for H_2S from the amine unit regenerator vent are 19.7 tpy and are therefore below the major source level. As a result, the CAM requirements do not apply to the amine unit regenerator (still) vent.

III. Emission Sources

CP CG-7101 - Solar Taurus, Model No. 70-10302S, Serial No. 0251B, Natural Gas Fired Combustion Turbine. The turbine is rated at 9,816 hp and 71.42 mmBtu/hr.

This turbine is equipped with a dry low NO_X combustion system to reduce NO_X emissions. This turbine powers a natural gas compressor.

CP CG-7201 - Solar Taurus, Model No. 70-10302S, Serial No. 0250B, Natural Gas Fired Combustion Turbine. The turbine is rated at 9,816 hp and 71.42 mmBtu/hr. This turbine is equipped with a dry low NO_X combustion system to reduce NO_X emissions. This turbine powers a natural gas compressor.

CP CG-7301 - Solar Taurus, Model No. 70-10302S, Serial No. 0286B, Natural Gas Fired Combustion Turbine. The turbine is rated at 9,816 hp and 71.42 mmBtu/hr. This turbine is equipped with a dry low NO_X combustion system to reduce NO_X emissions. This turbine powers a natural gas compressor.

1. Applicable Requirements – An initial approval construction permit (03WE0910) was issued for turbines CG-7101 and CG-7201 on June 10, 2004. In November 2004, the source applied for a modification to the permit in order to include alternative BACT limits for periods when the temperature is below 0 ° F. A revised construction permit was issued on March 29, 2005. Also in November 2004, the source applied for a construction permit for a third turbine, the construction permit (04WE1390) was issued on March 29, 2005. Turbines CG-7101 and CG-7201 started up on December 15, 2004. Turbine CG-7301 started up on October 29, 2005.

The source self-certified compliance with construction permit 03WE0910 on June 15, 2005, presumably with regards to the March 29, 2005 revised construction permit, but has not received a final approval permit. The source self-certification compliance with construction permit 04WE1390 on July 19, 2006, but has not received a final approval permit. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the modified initial approval construction permit have been incorporated into the renewal permit as follows:

Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (03WE0910, condition 1, 04WE1390, condition 1 and Regulation No. 1, Section II.A.1. & 4).

Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation. In addition, there are more specific activities under which the 30% opacity requirement applies than identified in the construction permit. The specific activities under which the 30% opacity standard applies are: building a new fire, cleaning of fire boxes, soot blowing, startup, any process modification, or adjustment or occasional cleaning of control equipment. Based on engineering judgment the Division considers that building a new fire, cleaning of fire boxes and soot-

blowing does not apply to the operation of combustion turbines. In addition, these turbines do not have add-on control devices, so adjustment or occasional cleaning of control devices do not apply to these turbines. Process modifications may apply to the turbines, however, based on engineering judgment, the Division believes that such activities would be unlikely to occur for longer than six minutes. Therefore, the 30% opacity requirement has been included in the operating permit for startup of these units.

- Construction of this source must commence within 18 months of permit issuance (04WE1390, condition 2).
- Startup notice shall be submitted within 30 days (04WE1390, condition 3).
 - As previously mentioned, CG-7301 has commenced operation, therefore, the above two requirements will not be included in the operating permit.
- Manufacturer, model and serial number shall be provided prior to final approval (03WE0910, condition 2 and 04WE1390, condition 4).

The source has supplied the manufacturer, model and serial number for each of the turbines, therefore, this requirement will not be included in the operating permit.

Each turbine is subject to the requirements of Prevention of Significant
Deterioration (PSD). Best Available Control Technology (BACT) shall be applied
for control of Oxides of Nitrogen (NO_X), Carbon Monoxide (CO) and Volatile
Organic Compounds (VOC) (03WE0910, condition 4 and 04WE1390, condition
6), as follows:

NO_X:

- SoLoNO_X II (DLN) combustion systems has been determined to be BACT for turbine CG-7301.
- SoLoNO_X (DLN) combustion systems has been determined to be BACT for turbines CG-7101 and CG-7201.
- Except as provided for below, NO_X emissions from turbine CG-7301 shall not exceed 15 ppmvd at 15% O₂ on a 1-hr average.
- Except as provided for below, NO_X emissions from turbines CG-7101 and CG-7201 shall not exceed 24.5 ppmvd at 15% O₂ on a 1-hr average.
- o When the ambient temperature is less than 0 ° F but greater than or equal to −20 ° F, NO_X emissions shall not exceed 42 ppmvd.
- o When the ambient temperature is less than −20 ° F, NO_X emissions shall not exceed 120 ppmvd.

CO:

o Good combustion practices has been determined to be BACT for the

turbines.

- Except as provided for below, CO emissions from turbines CG-7101 and CG-7201 shall not exceed 48.8 ppmvd at 15% O₂ on a 1-hr average.
- Except as provided for below, CO emissions from turbine CG-7301 shall not exceed 25 ppmvd at 15% O₂ on a 1-hr average.
- o When the ambient temperature is less than 0 ° F but greater than or equal to −20 ° F, CO emissions shall not exceed 100 ppmvd.
- When the ambient temperature is less than -20 ° F, CO emissions shall not exceed 150 ppmvd.

VOC:

- Good combustion practices and use of pipeline quality natural gas as fuel have been determined to be BACT for this turbine.
- Except as provided for below, VOC emissions shall not exceed 3 ppmvd at 15% O₂ on a 1-hr average
- o When the ambient temperature is less than 0 ° F but greater than or equal to −20 ° F, VOC emissions shall not exceed 5 ppmvd.
- o When the ambient temperature is less than −20 ° F, VOC emissions shall not exceed 8 ppmvd.
- For the alternative BACT limits during colder temperatures the source is required to keep records of the number of hours the temperature meets the specified criteria.
- Compliance with the BACT limits shall be demonstrated by conducting the performance tests required by the permits. Thereafter compliance with the NO_X and CO BACT limits will be monitored by conducting quarterly portable monitoring tests. At least annually, such portable monitoring shall be conducted at the low temperatures for which alternative BACT limits have been required, unless ambient conditions or extended periods at those temperatures are not sufficient to conduct monitoring.
- **Each turbine** is subject to the requirements in 40 CFR Part 60 Subpart GG Standards of performance for Stationary Gas Turbines, including, but not limited to the following (03WE0910, condition 5 and 04WE1390, condition 7):
 - NO_X limits shall not exceed 189.5 ppmvd at 15% O₂ and ISO conditions (§ 60.332(a)(2))
 - SO₂ emissions not to exceed 150 ppmvd at 15% O₂ or sulfur content of fuel not to exceed 0.8 % by weight (§ 60.333(a) and (b))

The construction permit specifies that compliance with the SO_2 emissions limits shall be presumed when burning pipeline quality natural gas and that the methods in 40 CFR Part 60 § 60.334(h)(3).

- In addition, the turbines are also subject to the NSPS General Provisions in 40 CFR Part 60 Subpart A, including, but not limited to the following (03WE0910, condition 5 and 04WE1390, condition 7):
 - Good practices (§ 60.11(d))
 - Circumvention (§ 60.12)
 - Record startup, shutdowns and malfunctions (§ 60.7(b))

Note that other requirements were noted in the construction permit but some of these requirements no longer apply (i.e. startup notification, performance test).

EPA promulgated new source performance standards for combustion turbines under 40 CFR Part 60 Subpart KKKK on July 6, 2006. These requirements apply to turbines that commenced construction, modification or reconstruction after February 18, 2005. Turbines CG-7101 and CG-7201 commenced operation on December 15, 2004, therefore, they are not subject to the requirements for newer turbines in 40 CFR Part 60 Subpart KKKK. The source submitted the application to add the turbine CG-7301 to the facility on November 10, 2004, although the permit was not issued until March 29, 2005. Commenced construction means that "the owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification." The source had entered into a contractual agreement to purchase the turbine prior to February 18, 2005. Therefore, turbine CG-7301 is not subject to the requirements in Subpart KKKK.

- **Each turbine** is subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part B Specific Facilities and Sources, Non-Federal NSPS, II Standards of Performance for New Fuel-Burning Equipment, D Standard for Sulfur Dioxide, 3 Combustion Turbines (03WE0910, condition 7 and 04WE1390, condition 9). These are **state-only requirements**.
 - o SO₂ emissions shall not exceed 0.8 lbs/mmBtu.
 - Opacity of emissions shall not exceed 20%

Although not specifically identified in the construction permit, the turbines are also subject to the particulate matter requirements in Reg 6, Part B, as follows:

- \circ Particulate matter emissions shall not exceed 0.5(FI) $^{\text{-0.26}}$ lbs/mmBtu, where FI = fuel input in mmBtu/hr
- Sulfur dioxide emissions from each turbine shall not exceed 0.8 lb/mmBtu (03WE0910, condition 8 and 04WE1390, condition 10 and Reg 1, Section VI.B.4.c.(i))

- Particulate matter emissions **from each turbine** shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI = fuel input in mmBtu/hr (03WE0910, condition 9 and 04WE1390, condition 11 and Reg 1, Section III.A.1.b).
- **Each turbine** shall be subject to the following fuel use limits (03WE0910, condition 10 and 04WE1390, condition 12):

Consumption of natural gas shall not exceed 56.2 mmSCF/mo and 661.5 mmSCF/yr

Note that the monthly fuel consumption limits apply during the first year of operation following issuance of the initial approval construction permit (04WE1390) modified initial approval construction permit (03WE0910) both issued on March 29, 2005 and since all three turbines will have been operating for more than one year upon issuance of this permit, the monthly limitations will not be included in the operating permit.

• **Each turbine** shall be subject to the following emission limits (03WE0910, condition 11 and 04WE1390, condition 13):

PM:	0.18 tons/mo	and	2.10 tons/yr
PM ₁₀	0.18 tons/mo	and	2.10 tons/yr
NO _X , CG-7101 & CG-7 2	201 2.68 tons/mo	and	31.6 tons/yr
NO _X , CG-7301	1.71 tons/mo	and	20.1 tons/yr
CO	3.27 tons/mo	and	38.5 tons/yr
VOC	0.96 tons/mo	and	11.3 tons/yr

Note that the monthly emission limits apply during the first year of operation following issuance of the initial approval construction permit (04WE1390) modified initial approval construction permit (03WE0910) both issued on March 29, 2005 and since all three turbines will have been operating for more than one year upon issuance of this permit, the monthly limitations will not be included in the operating permit.

In the construction permit for CG-7301 (04WE1390), the Division included a lower CO BACT limit than the source had originally requested in their application (25 ppm vs. 48.8 ppm). However, the annual CO emission limit included in the construction permit was based on the 48.8 ppm CO emission rate, rather than the permitted 25 ppm emission rate. Therefore, in the Title V permit, the Division lowered the CO emission limit to 20.9 tons/yr as indicated on the APEN submitted on March 30, 2007.

 The source is subject to the odor requirements in Regulation No. 2 (03WE0910, condition 6 and 04WE1390, condition 8). Turbines are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section IV) of the permit.

- Source compliance tests shall be conducted on the turbines to demonstrate compliance with the emission limitations (03WE0910, condition 12 and 04WE1390, Condition 14). Compliance tests have been completed on all three turbines, therefore, the performance test requirements will not be included in the permit.
- MACT initial notification requirements (03WE0910, condition 13 and 04WE1390, condition 15).

As discussed previously, the initial notifications have been submitted for the combustion turbines. The initial notification was submitted for CG-7101 and CG-7201 on June 15, 2005 and for CG-7301 on April 14, 2006. Therefore, this requirements will not be included in the permit.

 An application shall be submitted within one year of commencing operation to revise the Title V permit application (03WE0910, condition 14 and 04WE1390, condition 16).

An application for a separate Title V permit for the Cheyenne Plains equipment was submitted on December 15, 2005. Therefore, this requirement will not be included in the permit.

• Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (03WE0910, condition 15 and 04WE1390, condition 17).

As discussed above, the source submitted self-certifications for turbines CG-7101 and CG-7201 on June 10, 2005 and for CG-7301 on July 19, 2006. Therefore, this requirement will not be included in the permit.

 APEN reporting requirements (03WE0910, condition 16 and 04WE1390, condition 18)

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.

Streamlining of Applicable Requirements

Opacity

The turbines are subject to the Regulation No. 1 opacity standards and the Regulation No. 6, Part B opacity requirement. The Reg 1 20% opacity requirement applies at all

times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirement are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% opacity requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction (see attached opacity grid). While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. However, as discussed previously, the Division considers that for the turbine the only specific activity under which the 30% opacity standard would apply is startup. Therefore, since the Reg 1 20%/30% opacity requirements are more stringent than the Reg 6, Part B requirements the Reg 6 Part B opacity requirement has been streamlined out of the permit.

PM and SO₂

The turbines are subject to the Regulation No. 1 and No. 6, Part B PM and SO₂ standards. The PM and SO₂ requirements in both Reg 1 and Reg 6, Part B are the same standard. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, unless indicated otherwise in the specific subpart, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B PM and SO₂ requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 PM and SO₂ requirements are more stringent than the Regulation No. 6, Part B requirements and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

NO_X

The turbines are subject to the NSPS Subpart GG NO_X limits and BACT NO_X limits. The NSPS Subpart GG and BACT concentration limits are in the same units and therefore they can be compared for purposes of streamlining. The BACT averaging time is hourly. For purposes of reporting excess emissions under NSPS GG, turbines equipped with water and steam injection and continuous monitoring systems to record

the fuel consumption and the ratio of water/steam to fuel need to report every hour that the steam/water to fuel ratio falls below the acceptable level as determined by the performance test. This implies that the standard is on a 1-hour average. However, under the NSPS GG revisions, for units equipped with a continuous emission monitoring device or continuous parametric monitoring device, excess emissions are reported on a 4-hour rolling average. Therefore, the NSPS GG limit may be on either a 1-hour or a 4-hour rolling average, which is either an equal or less stringent averaging time than the BACT limit. The BACT concentration limits are applicable at all times. The Division considers that the NSPS Subpart GG requirements are not applicable during periods of startup, shutdown and malfunction (as discussed in the PM and SO₂ streamlining section above). Therefore, since the NSPS Subpart GG limits are less stringent than the BACT concentration limits, the NSPS Subpart GG limits will be streamlined out of the operating permit.

Miscellaneous

The turbines are subject to the NSPS general provisions (40 CFR Part 60) on a federal and state basis (the units are subject to 40 CFR Part 60 Subpart GG) and on a state-only basis (the units are subject to Reg 6, Part B, Section II and the NSPS general provisions are adopted by reference in Reg 6, Part B, Section I.A). Therefore, the Division will streamline the state-only NSPS general provisions out of the permit in favor of the state and federal NSPS general provisions.

In addition, since BACT for VOC is use of pipeline quality natural gas as fuel limits the sulfur content below the level of natural gas as defined in § 60.331(u), the Division will streamline out the sulfur monitoring requirements in NSPS GG (§ 60.334(h)(3)).

2. Emission Factors – The following emission factors shall be used to monitor compliance with the annual limitations:

	Emission Factors		Emission Factor Source
NO _X	CO	VOC	
T≥ 0 ° F: CG-7101 & CG-7201: 0.098 b/mmBtu CG-7301: 0.060 lb/mmBtu -20 ° F ≤ T < 0 ° F: 0.177 lb/mmBtu T < -20 ° F: 0.504 lb/mmBtu	T≥ 0 ° F: CG-7101 & CG-7201: 0.119 lb/mmBtu CG-7301: 0.061 lb/mmBtu -20 ° F ≤ T < 0 ° F: 0.257 lb/mmBtu T < -20 ° F: 0.384 lb/mmBtu	T≥ 0 $^{\circ}$ F: 0.035 lb/mmBtu -20 $^{\circ}$ F ≤ T < 0 $^{\circ}$ F: 0.070 lb/mmBtu T < -20 $^{\circ}$ F: 0.105 lb/mmBtu	Manufacturer's Info: T≥0° F: CG-7101 and CG-7201: based on 100% load, at 0° F. NO _X based on adjusting 0.10 lb/mmBtu factor to 24.5 rather than 25 ppm. CO is based on adjusting the 0.122 lb/mmBtu factor to 48.8 pm, rather than 50 ppm. CG-7301: NO _X and CO based on manufacturer's data sheet (at 59 ° F). All Turbines: VOC based on total UHC. For the lower temperatures the emission factors are based on the above emission factors adjusted to the higher ppm limit.

Emissions of PM, PM₁₀ and SO₂ were estimated using the following emission factors (from AP-42, Section 3.1 (dated April 200), Table 3.1-2a):

Pollutant	Emission Factor
PM	6.6 x 10 ⁻³ lb/mmBtu
PM ₁₀	6.6 x 10 ⁻³ lb/mmBtu
SO ₂	3.4 x 10 ⁻³ lb/mmBtu

Note that since SO₂ emissions from each turbine are below the APEN de minimis level, so a limit for SO₂ is not included in the permit; however, emissions from all criteria pollutants are to be included on any revised APENS.

- **3. Monitoring Requirements -** The source will be required to monitor fuel consumption and calculate monthly emissions to monitor compliance with the fuel consumption and emission limitations. Quarterly portable monitoring shall be required to monitor compliance with the NO_X and CO BACT emission limitations, emission factors and annual emission limitations. Compliance with the VOC BACT emission limits is presumed provided pipeline quality natural gas is used as fuel and good combustion practices are applied.
- **4. Compliance Status** The source indicated in the Title V permit application that these emission units were in compliance with the applicable requirements. The Division would agree with this assessment.

H-8701: Heatec, Model No. VHC1-160101-40-G, Serial No. 04-074-151, Natural Gas-Fired Hot Oil Heater, Rated at 45 mmBtu/hr.

H-8702: Heatec, Model No. VHC1-160101-40-G, Serial No. 04-074-152, Natural Gas-Fired Hot Oil Heater, Rated at 45 mmBtu/hr.

1. Applicable Requirements - An initial approval construction permit (03WE0913) was issued for heaters H-8701 and H-8702 on June 10, 2004. The hot oil heaters commenced operation on January 30, 2005. After conducting the performance tests on these units, the source submitted an application on October 31, 2005 to modify the permit for these units to revise the NO_X BACT limit and to remove the utility heater from the permit. The source requested the modification because the heaters were unable to comply with the NO_X BACT limits when operating at lower loads and the utility heater burners would be replaced with new burners, which would make reduce the capacity of the heater to 4.5 mmBtu/hr, thus making the unit exempt from the APEN reporting and construction permit requirements.

The source had not submitted a self-certification for these units because they could not meet the BACT limits for NO_X at low loads. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the heaters commenced operation. Therefore, under the provisions of Regulation No. 3,

Part C, Section V.A.2., the Division is allowing the initial approval construction permit to continue in full force and effect and will consider the Responsible Official certification submitted with that report to serve as the demonstration required pursuant to Regulation No. 3, Part B, Section IIi.G.2 and no final approval construction permit will be issued. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit as indicated in the following discussion:

 Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 1 and Regulation No. 1, Section II.A.1. & 4).

As discussed above under the turbines, Reg 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation. In addition, there are more specific activities under which the 30% opacity requirement applies than identified in the construction permit. The specific activities under which the 30% opacity standard applies are: building a new fire, cleaning of fire boxes, soot blowing, startup, any process modification, or adjustment or occasional cleaning of control equipment. Based on engineering judgment the Division considers that building a new fire, cleaning of fire boxes and soot-blowing does not apply to the operation of the hot oil heaters. In addition, the heaters do not have an add-on control device, so adjustment or occasional cleaning of control devices do not apply to these heaters. Process modifications may apply to the heaters, however, based on engineering judgment, the Division believes that such activities would be unlikely to occur for longer than six minutes. Therefore, the 30% opacity requirement has been included in the operating permit for startup of the heaters.

 Manufacturer, model and serial number shall be provided prior to final approval (condition 2).

The source has supplied the manufacturer and model. The Division will request the serial number for each of the heaters during the pre-public comment review period.

Each heater is subject to the requirements of Prevention of Significant
Deterioration (PSD). Best Available Control Technology (BACT) shall be applied
for control of Oxides of Nitrogen (NO_X), Carbon Monoxide (CO) and Volatile
Organic Compounds (VOC) (condition 4), as follows:

NO_X :

o Low NO $_{\rm X}$ burners shall be used to limit the NO $_{\rm X}$ emissions from each heater to 0.045 lb/mmBtu, on a 1-hr average.

CO:

o Good combustion practices shall be used to limit the CO emissions from

each heater to 0.037 lb/mmBtu, on a 1-hr average.

VOC:

- Good combustion practices shall be used to limit the VOC emissions from each heater to 0.016 lb/mmBtu, on a 1-hr average.
- **Each heater** shall be subject to the following fuel use limits (condition 5):

Consumption of natural gas shall not exceed 416.8 mmSCF/yr

• **Each heater** shall be subject to the following emission limits (condition 6):

0	NO_X	8.9 tons/yr
0	CO	7.3 tons/yr
0	VOC	3.15 tons/yr

- Particulate matter emissions **from each heater** shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI = fuel input in mmBtu/hr (condition 7 and Reg 1, Section III.A.1.b).
- Each heater is subject to the requirements in 40 CFR Part 60 Subpart Dc Standards of performance for Small Industrial-Commercial-Institutional Steam Generating Units, including, but not limited to the following (condition 8):
 - Notification requirements in accordance with 40 CFR Part 60 Subpart Dc § 60.48c(a).
 - Record quantity so fuel burned per calendar month in accordance with 40 CFR Part 60 Subpart Dc § 60.48c(g).
 - Retain records for two years in accordance with 40 CFR Part 60 Subpart Dc § 60.48c(i).

Note that the notification requirements have been fulfilled; therefore, that requirement will not be included in the permit.

- In addition, the heaters are also subject to the NSPS General Provisions in 40 CFR Part 60 Subpart A, including, but not limited to the following (condition 8):
 - Good practices (§ 60.11(d))
 - Circumvention (§ 60.12)
 - Record startup, shutdowns and malfunctions (§ 60.7(b))
- Each heater is subject to Regulation No. 6 Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II – Standards of Performance for New Fuel-Burning Equipment, D – Standard

for Sulfur Dioxide, 3 – Combustion Turbines (condition 9). These are **state-only requirements**.

- Opacity of emissions shall not exceed 20%
- Particulate matter emissions shall not exceed 0.5(FI)^{-0.26} lbs/mmBtu, where FI = fuel input in mmBtu/hr
- An application shall be submitted within one year of commencing operation to revise the Title V permit application (condition 10).

An application for a separate Title V permit for the Cheyenne Plains equipment was submitted on December 15, 2005. Therefore, this requirement will not be included in the permit.

APEN reporting requirements (condition 11).

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.

 The source is subject to the odor requirements in Regulation No. 2 (condition 12).

Heaters are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section IV) of the permit.

- Each heater is subject to Regulation No. 8, part E, Section IIII Federal Maximum Achievable Control Technology (MACT) requirements in 40 CFR Part 63 Subpart DDDDD National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters. As discussed previously, on July 30, 2007 the Boiler MACT provisions were vacated and as such the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect or enforceable. Vacatur of the Boiler MACT provisions triggers the case-by-case MACT requirements and a requirement to submit the 112(j) application has been included in the permit.
- Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (condition 14).

As discussed above, the Division will consider that the Responsible Official's certification submitted with the first semi-annual monitoring report will serve as the self-certification that these emission units can comply with the applicable requirements.

 No rain caps or other obstructions are allowed on the exhaust stacks for these heaters (condition 15).

Streamlining of Applicable Requirements

Opacity

The heaters are subject to the Regulation No. 1 opacity standards and the Regulation No. 6, Part B opacity requirement. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% opacity requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction (see attached opacity grid). While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. However, as discussed previously, the Division considers that for the heaters the only specific activity under which the 30% opacity standard would apply is startup. Therefore, since the Reg 1 20%/30% opacity requirements are more stringent than the Reg 6, Part B requirements the Reg 6 Part B opacity requirement has been streamlined out of the permit.

PM

The heaters are subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. As indicated under the particulate matter and sulfur dioxide streamlining section for the turbines the Reg 6, Part B particulate matter requirements are not applicable during startup, shutdown and malfunction. As a result, the Reg 6, Part B requirements have been streamlined out of the permit.

Recordkeeping

NSPS Dc requires that records be kept for a period of 2 years, while Reg 3, Part C, Section V.C.6 requires that records be retained for five (5). Therefore, the NSPS recordkeeping requirement will be streamlined out of the permit.

Miscellaneous

The heaters are subject to the NSPS general provisions (40 CFR Part 60) on a federal and state basis (the units are subject to 40 CFR Part 60 Subpart GG) and on a state-only basis (the units are subject to Reg 6, Part B, Section II and the NSPS general provisions are adopted by reference in Reg 6, Part B, Section I.A). Therefore, the

Division will streamline the state-only NSPS general provisions out of the permit in favor of the state and federal NSPS general provisions.

2. Emission Factors - The following emission factors shall be used to monitor compliance with the annual limitations:

Unit	Emissi	on Factors (lbs/n	nmBtu)	Emission Factor Source
	NO_X	CO	VOC	
H-8701	0.045	0.037	0.016	CO and VOC from Manufacturer's Data.
H-8702	0.045	0.037	0.016	NO _X based on performance test conducted on June 8, 2005 for H-8701 at 43% load.

- **3. Monitoring Requirements** The source will be required to record fuel use and calculate emissions monthly to monitor compliance with the annual limitations. The Division will require annual portable monitoring to verify compliance with the NO_X and CO BACT emission limitations. Compliance with the PM and opacity limitations are presumed, in the absence of credible evidence to the contrary since natural gas is the only fuel permitted for use in these units.
- **4. Compliance Status** The source indicated in the Title V permit application that the heaters were in compliance with all applicable requirements. The Division agrees that upon issuance of the construction permit to revise the NO_X BACT limits [October 19, 2006] for these units that the heaters are in compliance with all applicable requirements.

CO₂ Treatment Plant – Glycol Dehydrator and Amine Unit Rated at 300 mmSCF/day

FL-8921: Flare Vent. Emissions from the Glycol Dehydrator Regenerator (Still) Vent and Flash Tank and the Amine Unit Flash Tank are Routed to the Flare. The flare is rated at 13.54 mmBtu/hr.

ST-8931: Amine Unit Regenerator (Still) Vent, Routed to SulfaTreat H₂S Control System.

1. Applicable Requirements - An initial approval construction permit (03WE0916) was issued for the CO₂ Treatment Plant on June 10, 2004. A revised construction permit was issued on May 23, 2005, to correct errors in the monthly emission rates. The CO₂ plant commenced operation on January 30, 2005.

The source self-certified compliance with construction permit 03WE0916 on July 29, 2005, but has not received a final approval permit. Therefore, under the provisions of Colorado Regulation No. 3, Part C, Section V.A.3, the Division will not issue a final approval construction permit and is allowing the initial approval construction permit to continue in full force and effect.

The appropriate applicable requirements from the modified initial approval construction permit have been incorporated into the renewal permit as follows:

 Visible Emissions shall not exceed 20 % opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (condition 1 and Regulation No. 1, Section II.A.1. & 4).

The 20% / 30 % opacity requirement applies to the amine unit regenerator vent (the flare is subject to a different Reg 1 opacity requirement as mentioned below). However, the regenerator vent exhaust consists primarily of CO_2 and VOC emissions. Typically the Division does not include the opacity limit in permits for VOC sources, therefore, the 20% / 30% opacity limit will not be included in the permit.

- No owner or operator of a smokeless flare or other flare for the combustion of waste gases shall allow or cause emissions into the atmosphere of any air pollutant which is in excess of 30% opacity for a period or periods aggregating six minutes in any sixty consecutive minutes (condition 2 and Regulation No. 1, Section II.A.5).
- Construction of this source must commence within 18 months of initial approval permit issuance (condition 3).
 - As previously indicated, the CO₂ plant commenced operation on January 30, 2005; therefore, this condition will not be included in the permit.
- The manufacturer, model number and serial number of the subject equipment shall be provided for the Division prior to Final Approval (condition 4).
 - The source provided this information with their self-certification, therefore, this condition will not be included in the permit.
- The permittee shall notify the Division of startup (condition 6).
 - As previously indicated, the CO₂ plant commenced operation on January 30, 2005; therefore, this condition will not be included in the permit.
- The CO₂ treatment plant is subject to the requirements of Prevention of Significant Deterioration (PSD). Best Available Control Technology (BACT) shall be applied for Volatile Organic Compounds (VOC) (condition 7), as follows:

VOC:

- Use of an elevated flare shall be used to reduce emissions of VOC by 98%
 - Note that the flare is an air-assisted flare.
- o Compliance with the 98% control efficiency is presumed, provided the

flare is operated in accordance with the requirements in 40 CFR Part 63 Subpart HHH and the supplemental fuel requirement is met.

- The amine unit is subject to Regulation No. 6 Standards of Performance for New Stationary Sources (NSPS), Part A, Subpart LLL – Standards of Performance for Onshore Natural Gas Processing: SO₂ Emissions, as follows:
 - The owner or operator shall keep for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 long tons per day of H₂S expressed as sulfur (40 CFR part 60 Subpart LLL § 60.647(c)).

Because this unit is exempt from the control requirements, the Division has presumed that the unit is also exempt from the requirements in 40 CFR Part 60 Subpart A.

- The glycol dehydrator is subject to Regulation No. 8, Part E, Section III Federal Maximum Achievable Control (MACT) requirements in 40 CFR Part 63 Subpart HHH – National Emission Standards for Hazardous Air Pollutants for Natural Gas Transmission and Storage Facilities, including but not limited to the following:
 - The unit shall comply upon startup (40 CFR Part 63 Subpart HHH § 63.1270(d)(2)).
 - Startup, shutdown and malfunction requirements in 40 CFR Part 63 Subpart HHH § 63.1272.
 - General standards in 40 CFR Part 63 Subpart HHH § 63.1274.
 - Glycol dehydrator unit process vent standards in 40 CFR Part 63 Subpart HHH § 63.1275.
 - Control equipment requirements in 40 CFR Part 63 Subpart HHH § 63.1281.
 - Test Methods, Compliance Procedures and Compliance Demonstrations requirements in 40 CFR Part 63 Subpart HHH § 63.1282.
 - Inspection and Monitoring requirements in 40 CFR Part 63 Subpart HHH § 63.1283.
 - Recordkeeping requirements in 40 CFR Part 63 Subpart HHH § 63.1284.
 - Reporting requirements 40 CFR Part 63 Subpart HHH § 63.1285.

In addition, the general provisions from 40 CFR Part 63 Subpart A also apply and will be included as appropriate.

 Emissions from the amine unit regenerator vent shall be routed to the SulfaTreat H₂S control system at all times the amine unit is operation. A control efficiency of 75% may be used to calculate emissions is the unit is operated and maintained in accordance with manufacturer's recommendations and good engineering practices (condition 10).

- Emissions from the glycol dehydrator regenerator and flash tank and emissions
 from the amine unit flash tank shall be routed to the flare at all times the glycol
 dehydrator and amine unit are operating. A control efficiency of 98% for the flare
 may be used to calculate emissions provided the flare is operated in accordance
 with the requirements in 40 CFR part 63 Subpart A § 63.11(b) and 40 CFR Part
 63 Subpart HHH (condition 11)
- The CO₂ Treatment Plant shall be subject to the following emission limits (condition 12):

Fla	are Vent			
0	VOC	0.5 tons/mo	and	5.8 tons/yr
0	NO_X	0.63 tons/mo	and	7.4 tons/yr
0	CO	3.4 tons/mo	and	39.42 tons/yr
C	D ₂ Vent (Amine Unit	t Regenerator)		
0	VOC	1.0 tons/mo	and	11.8 tons/yr
0	H_2S	0.42 tons/mo	and	5.0 tons/yr

Note that the monthly emission limits apply during the first year of operation and since the CO₂ treatment plant has been operating for more than one year the monthly limits will not be included in the operating permit.

In addition, under the Natural Gas Transmission and Storage MACT, the source indicated that they would meet the 1 ton/yr benzene emission limitations. The NGTS MACT does not include procedures to calculate benzene emissions from the dehydrator. The MACT only addresses the method required to demonstrate that a source is exempt from the MACT control requirements because actual benzene emissions are less than 1 ton/yr (40 CFR Part 63 Subpart HHH § 63.1282(a)). Therefore, the Division has included a benzene emission limit in the permit for the dehydrator. The benzene emission limit is based on the GLYCalc run used to set the VOC permit limits and are set at 0.90 tons/yr of benzene.

- The CO₂ Treatment Plant shall be subject to the following processing/throughput limits (condition 13):
 - Processing of natural gas to the plant shall not exceed:
 - 9.300 mmscf/mo and 109,500 mmSCF/yr
 - Supplemental fuel to the flare shall not be less than 0.335 mmBtu/hr

Note that the monthly processing/throughput limits apply during the first year of operation and since the CO₂ treatment plant has been operating for more than one year the monthly limits will not be included in the operating permit.

In their comments on the draft permit, received on January 11, 2007, the source indicated that the supplemental fuel requirement, which was based on the GLYCalc run used to set the permit limits, did not take into account the additional

gases from the amine unit flash tank that are routed to the flare. They indicated that since the amine unit always runs when the glycol dehydrator runs; therefore, the supplemental fuel requirement is fulfilled by the amine unit flash tank emissions that are routed to the flare. The Division reviewed the data in the GLYCalc and AMINE Calc runs that were used to set the permit limits and agree that the heat content of the gases routed to the flare exceed 300 Btu/scf without supplemental fuel. Therefore, the supplemental fuel requirement was not included in the draft permit. However, the Division did include a requirement that the glycol dehydrator and the amine unit shall always be run at the same time (e.g. the glycol dehydrator cannot run if the amine unit is not running and vice versa).

 The source is subject to the odor requirements in Regulation No. 2 (condition 14).

Heaters are not generally a source of odor therefore this condition will not be specifically included in the permit but is included in the General Conditions (Section IV) of the permit.

 An application shall be submitted within one year of commencing operation to revise the Title V permit application (condition 15).

An application for a separate Title V permit for the Cheyenne Plains equipment was submitted on December 15, 2005. Therefore, this requirement will not be included in the permit.

 Within 180 days after commencement of operation, compliance with the conditions contained on this permit shall be demonstrated to the Division (condition 16).

As discussed above, the source submitted a self-certification on July 28, 2005, therefore, this requirement will not be included in the permit.

• Prior to issuance of final approval, the source shall submit to the Division for approval an operating and maintenance plan for all control equipment and control practices (condition 17).

An operations and maintenance plan was submitted for the flare on August 1, 2005 but no plan was submitted for the SulfaTreat unit. The operating permit will include the appropriate requirements to monitor compliance with the permit terms. The operating and maintenance requirements proposed by the source in their operating and maintenance plan have been considered for inclusion in the permit.

APEN reporting requirements (condition 18).

The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.

2. Emission Factors – The CO₂ Treatment Plant operates as a single train, with natural gas passing through the amine unit to remove primarily CO₂ (with some H₂S removed also) then through the glycol dehydrator.

In the amine unit, natural gas is processed through an aqueous solution of monoethanolamine (MEA) that will absorb H₂S, CO₂ and VOCs. After the amine solution is saturated with the acid gases it is piped to the amine regenerator. The regenerator heats the amine solution and the acid gases and VOCs are released.

In the glycol dehydration unit, triethylene glycol is contacted with the natural gas stream to remove moisture. This glycol-water mixture is heated in the still vent portion of the unit which drives off the water and some entrained VOCs.

Emissions from the amine unit are estimated using the Gas Research Institute's AMINECalc Model and emissions from the glycol dehydrator are estimated using Gas Research Institute's GLYCalc Model. Emission factors of VOC and various HAPs are dependent upon the variables input into these models. Variables for the amine unit include lean amine weight, pressure, temperature and flowrate, H₂S and CO₂ loading, control device efficiency, flash tank pressure, number of trays in the column and the pressure, temperature, flowrate and composition of the inlet gas. Variables for the glycol dehydrator include glycol recirculation rate, cubic feet of gas processed, inlet temperature and pressure of the processed wet gas, flash tank temperature and pressure, the control efficiency of the flare and percentage breakdown by volume of constituents in the natural gas.

Emissions of NO_X and CO are generated from the flare when the gases from supplemental fuel and the glycol dehydrator still vent and flash tank vent are combusted. Emissions for these pollutants are estimated using the following emission factors:

Pollutant	Emission Factor	Source
NO _X	0.068 lb/mmBtu	AP-42, Section 13.5 (dated 9/91), Table 13.5-1
CO	0.37 lb/mmBtu	

Note that there are additional VOC emissions generated from the combustion of the supplemental fuel by the flare. However, compared to the VOC emission from the glycol dehydrator, these emissions are insignificant (less than 0.5 ton/yr) and will therefore not be included in the permit.

3. Monitoring Requirements –The wet gas (inlet) temperature, glycol recirculation rate, and gas BTEX content as the three critical inputs to the GRI GLYCalc Model for triethylene glycol units. Changes to the gas flow rate and inlet pressure do not radically

affect emissions from glycol dehydrators. Therefore, parametric monitoring of the inlet temperature, recirculation rate and BTEX content will be required as part of the monitoring plan for the glycol dehydrator. Inlet pressure and flash tank temperature and pressure will be held constant for modeling purposes. Modeling will only be required when the defined values for inlet temperature, recirculation rate and BTEX content are not indicative of operating conditions during the month. The frequency of sampling and analysis of the wet gas BTEX concentration is quarterly, with provisions to reduce sampling and analysis if the concentrations used in the GLYCalc analysis are met. Frequency of monitoring for other parameters (wet gas temperature and glycol circulation rate) will be daily. The performance of the flare shall be monitored as required by the MACT.

The Division has less information on AMINECalc but we would assume that similar important parameters would be monitored. Therefore, the Division will require monitoring of the lean amine flowrate, the inlet gas temperature and the BTEX composition of the inlet gas. As with the GLYCalc parameters, required frequency of monitoring would be daily for the lean amine flowrate and the inlet gas temperature and the Division would require quarterly analysis to determine the BTEX composition of the inlet gas, with provisions to reduce the frequency if the concentrations used in the AMINECalc analysis are met. The amine regenerator vent is routed through the SulfaTreat to reduce H₂S emissions. Manufacturer's information on this unit indicates that the only required monitoring is the outlet H₂S concentration in order to determine when the SulfaTreat material must be replaced.

4. Compliance Status – The source indicated that the CO₂ Treatment Plant is in compliance with all applicable requirements. The Division would agree with this assessment.

CP EG-6141: Caterpillar, Model No. 3516B LE, Serial No. CTW00511, 4-Cycle Lean Burn Internal Combustion Engine, Rates at 1557 hp and 10.95 mmBtu/hr. This engine is used to drive an emergency generator.

1. Applicable Requirements - Based on the size of the generator, this unit would be exempt from the APEN reporting requirements provided that the unit is operated for no more than 100 hrs/yr (Colorado Regulation No. 3, Part A, Section II.D.1.ttt(ii)). However, in their construction permit application for the Cheyenne Plains facility, the source indicated that this unit would operate more than 100 hrs/yr but less than 250 hrs/yr. As a result an APEN would be required for the engine but a construction permit was not required under the provisions of Colorado Regulation No. 3, Part B, Section II.D.1.c.(ii)). Since the emergency generator is not exempt from the APEN reporting requirements, it cannot be considered an insignificant activity. Therefore, the emergency generator will be included in the Title V permit as a significant emission unit.

In addition to the APEN reporting requirements, the Division considers the engine is also subject to the 20% and 30 % opacity requirements in Colorado Regulation No. 1, Sections II.A.4. The 30% opacity requirement applies during certain specific conditions

(building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment. The Division considers that building a new fire, cleaning of fire boxes and soot blowing are activities that do not apply to natural gas fired internal combustion engines. In addition, the engine is not equipped with any add-on control device, so adjustment or occasional cleaning of control equipment do not apply to this engine. In addition, although process modifications and/or start-up are conditions that would apply to this engine, the Division considers that such activities would not last for more than six minutes; therefore, the Division considers that the 30% opacity requirement does not apply to this engine.

2. Emission Factors - Emissions from this engine is from the combustion of natural gas. The pollutants of concern are Particulate Matter, (PM and PM₁₀), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO₂), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Some hazardous air pollutants (HAPs) are generated through the combustion process, although emissions are minimal. Approval of emission factors for this unit is necessary to the extent that accurate actual emissions are required to verify the need to submit revised APENs to update the Division's Emission Inventory.

In the Title V permit application the source indicated that they were basing emissions from the engine on NO_X , CO and VOC emissions factors from the manufacturer, they estimated PM, PM_{10} and SO_2 emissions from AP-42, Section 3.2 (dated July 200), Table 3.2-2 (4-stroke lean burn engines). The emission factors as follows:

Pollutant	Emission Factor				
PM	9.99 x 10 ⁻³ lb/mmBtu				
PM ₁₀	9.99 x 10 ⁻³ lb/mmBtu				
SO ₂	5.88 x 10 ⁻⁴ lb/mmBtu				
NO _X	1 g/hp-hr				
CO	3.04 g/hp-hr				
VOC	0.86 g/hp-hr				

Note that at 250 hrs/yr of operation, PM, PM₁₀, VOC and SO₂ emissions are below the APEN de minimis level, so the source will not be required to calculate emissions of these pollutants from this unit; however, emissions from all criteria pollutants are to be included on any revised APENS.

- **3. Monitoring Requirements -** The source will be required to record hours of operation annually for purposes of calculating emissions to determine APEN reporting requirements. Emissions shall be based on hours of operation and the maximum horsepower of the engine. Note that in the absence of credible evidence to the contrary, compliance with the opacity limitation is presumed since natural gas is the only fuel permitted to be used as fuel for this engine.
- **4. Compliance Status** The Title V permit application did not include the emergency generator. However, since the generator is only subject to APEN reporting requirements and an APEN was submitted indicating actual emissions as potential

emissions (based on 250 hrs/yr of operation) within the last five years, the engine is in compliance with the APEN reporting requirements.

IV. Insignificant Activities

The source indicated that the following general categories of insignificant activities at this site include: individual fuel burning equipment < 5 mmBtu/hr and emission units with emissions less than APEN de minimis levels. The following list of specific insignificant activities was included in the Title V application.

<u>Units with emissions less than APEN de minims –criteria pollutants (Reg 3, Part C.II.E.3.b)</u>

Emergency shutdowns (VOC emissions < 2 tons/yr)
Fugitive VOC emissions from Equipment leaks (VOC emissions < 2 tons/yr)
Compresser blowdowns (VOC emissions < 2 tons/yr)
Turbine startups (VOC emissions < 2 tons/yr)

Fuel (gaseous) burning equipment < 5 mmBtu/hr (Reg 3, Part C.II.E.3.k)

Utility heater, 4.5 mmBtu/hr Glycol dehydrator reboiler (4.97 mmBtu/hr total, two burners, each 2.485 mmBtu/hr)

V. Alternative Operating Scenarios

No alternative operating scenarios were requested for this facility.

VI. Permit Shield

Permit Shield for Non-Applicable Requirements

The source did not request the permit shield for any non-applicable requirements.

Permit Shield For Streamlined Requirements

These requirements are applicable to the emission units at the Cheyenne Plains Compressor Station. As discussed previously in this document, under streamlining of applicable requirements, the Division has included the above requirements, as appropriate in the permit shield for streamlined/subsumed conditions.

The following applicable requirements were streamlined out of the permit **for the turbines** and have been included in the permit shield.

 State-only – 20% opacity (Reg 6, Part B, Section II.C.3), streamlined out since Reg 1 20% / 30% opacity requirement is more stringent.

- **State-only** PM emissions shall not exceed 0.5(FI)^{-0.26} lb/mmBtu (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 PM requirement is more stringent.
- **State-only** 0.35 lbs/mmBtu SO₂ requirement (Reg 6, Part B, Section II.D.3.b), streamlined out since Reg 1 SO₂ requirement is more stringent.
- State-only NSPS general provisions (Reg 6, Part B, Section I), streamlined out since units are subject to federal NSPS general provisions.
- 189.5 ppmvd NO_X at 15% O₂ and ISO conditions (40 CFR Part 60 Subpart GG § 60.332(c)) streamlined out since NO_X BACT limit is more stringent.
- Monitor sulfur content of fuel (40 CFR Part 60 Subpart GG § 60.334(h)(3)), streamlined out in favor of the BACT requirement to use pipeline quality natural gas.

The following applicable requirements were streamlined out of the permit **for the hot oil heaters** and have been included in the permit shield.

- State-only 20% opacity (Reg 6, Part B, Section II.C.3), streamlined out since Reg 1 20% / 30% opacity requirement is more stringent.
- **State-only** PM emissions shall not exceed 0.5(FI)^{-0.26} lb/mmBtu (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 PM requirement is more stringent.
- **State-only** NSPS general provisions (Reg 6, Part B, Section I), streamlined out since units are subject to federal NSPS general provisions.
- Retain records for two (2) years (40 CFR Part 60 Subpart Dc § 60.48c(i)) streamlined in favor of Title V recordkeeping requirements.

HAPs Per Division Analysis (05OPWE281)

11.7	ı			Hazardo	ous Air Pollu	tant Emissio	ons, in Tons	⁄yr				ī
Unit	acetaldehyde	benzene	ethlybenzene	formaldehyde	toluene	xylene	2,2,4- trimethylpentane	methanol	Nickel	n-hexane	acrolein	Total
Turbine (CG-7101) Turbine (CG-7201)	0.01 0.01	0.00	0.01 0.01	0.22 0.22	0.04 0.04	0.02 0.02						0.30 0.30
Hot Oil Heater (H-8701)	0.01	0.00	0.01	0.02	0.00	0.02			0.00	0.38		0.40
Hot Oil Heater (H-8703)		0.00		0.02	0.00				0.00	0.38		0.40
Dehydrator		0.87			1.56					0.11		2.54
Amine Unit		7.35			2.30					0.10		9.74
Phase II Turbine (CG-7301)	0.01	0.00	0.01	0.22	0.04	0.02						0.30
Emergency Generator (CP EG- 6141)**	0.01			0.07							0.01	0.09
Total	0.04	8.23	0.03	0.76	3.97	0.06	0.00	0.00	0.00	0.96	0.01	14.07

Insignificant activities included in HAP total in the preliminary analyses for the FREP, CPP and CPP Phase II turbine are not included here.

^{**}Based on 250 hrs/yr of operation